Chapter Six: Specific Issues Relating to Oil and Gas Exploration, Development, Production and Transportation

Contents

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A. Geophysical Hazards

The primary geophysical hazards within the Sale 87 area include earthquakes, faulting, shore-ice movement, permafrost and frozen-ground phenomena, waves, coastal erosion, seasonal flooding, overpressured sediments, and shallow gas deposits and hydrates. These geohazards could impose constraints to exploration, production, and transportation activities associated with possible petroleum development, and should be considered prior to the siting, design and construction of any facilities.

1. Faults and Earthquakes

Surface faults[1] have been mapped throughout the Central Beaufort including high-angle faults, basement-involved[2] normal faults, listric growth faults[3,] and north-dipping gravity faults[4.] Locally, two or more types may occur in close proximity to each other.

High-angle faults occur along the Barrow Arch extending into Harrison Bay. Along the Barrow Arch[5] they are related to the basement tectonics of the Arctic Platform[6] while in Harrison Bay, they offset the Tertiary and older units (See Table 2.2). There has been little evidence of any Quaternary movement, with no evidence of displacement in the Pleistocene or Holocene sediments, and there has been no recent seismicity associated with these faults. Thus, differential movement along these faults seems to have ended prior to the beginning of the Quaternary Period (Craig and Thrasher, 1982).

A number of shallow faults have been mapped north of the Arctic Platform. Included in these faults are the upper extensions of detached listric growth faults that exist deep in the Brookian[7] section. These faults have been mapped in the greatest detail in the Camden Bay area where some of these faults may have been reactivated in the late Cenozoic and can have several tens of meters of offset. Shallow faults have also been mapped beneath the outer shelf, west of Cape Halkett, and are reported to show from 3 to 10 meters of Quaternary offset (Grantz and others, 1983).

In contrast to the rest of the Beaufort shelf, the Camden Bay area, just east of the sale area, is still seismically active. This region is located at the northern end of a north-northeast trending band of seismicity that extends north from east-central Alaska (Biswas and Gedney, 1979). Since monitoring began in 1978, a large number of earthquakes, ranging from magnitude one to over five, have been recorded in this area, with

[1] A fault is a surface or zone of rock fracture along which there has been displacement, from a few centimeters to a few kilometers in scale (American Geological Institute, Glossary of Geology, 1973).
[2] The term “basement” refers to the surface beneath which sedimentary rocks are not found (Encyclopedic Dictionary of Exploration Geophysics, 1991).
[3] A “listric” surface is a curvilinear, usually concave-upward surface of fracture that curves, at first gently and then more steeply, from a horizontal position. Listric surfaces form wedge-shaped masses, appearing to be thrust against or along each other (American Geological Institute, Glossary of Geology, 1973).
[4] A gravity fault is a normal fault that shows downward displacement. .
[5] The Barrow arch is a broad structure in the basement rocks that has elevated all successive strata.
[6] A “platform” refers to that part of a continent which is covered by a flat-lying or gently tilted strata, mainly sedimentary, which are underlain at varying depth by a basement of racks that were consolidated during earlier deformations (American Geological Institute, Glossary of Geology, 1973).
[7] The Brookian section began about 100 million years ago and continues into the late Tertiary.

the majority of events clustering along the axis of the Camden anticline[8]. The largest earthquake recorded in the area was a magnitude 5.3 event located 30 km north of Barter Island in 1968. In this region, the Tertiary and Quaternary units dip away from and are truncated at the top of the Camden anticline, indicating that it has been growing in recent geologic time. The faults in this region trend northwest-southeast, parallel to the Hinge Line[9,] and as they approach and intersect the axis of the Camden anticline, they offset progressively younger units. This suggests that these faults are older Hinge Line-related structures that were reactivated during late Tertiary and Quaternary by the uplift of the Camden anticline.

North of the sale area, on the outer Beaufort shelf and upper slope are gravity faults that are related to large rotational slump blocks[10] (Grantz and Dinter, 1980). South of these slumps, which bound the seaward edge of the Beaufort Ramp, these faults have surface offsets ranging from 15 meters to as high as 70 meters (Grantz and others, 1982b). Grantz and others (1982b) have inferred that these faults have been active in recent geologic time based on the age of the faults and therefore pose a hazard to bottom-founded structures in this area. Large-scale gravity slumping of the blocks here could be triggered by shallow-focus earthquakes centered in Camden Bay or in the Brooks Range.

Figure 6.1 shows the locations of recorded earthquake epicenters in the Sale 87 area. Most of the seismicity in the region is shallow (less than 20 miles deep), indicating near-surface faulting. Recent significant events include two magnitude 5 earthquakes in the eastern part of the sale area, one in 1993 and one in 1995. The largest event in the region was a magnitude 5.3 earthquake north of Kaktovik in 1968. (Combellick, 1998)

Algermissen and others (1991) estimate a 10 percent probability of exceeding 0.025 g[11] earthquake-generated horizontal acceleration in bedrock during a 50-year period in the eastern part of the sale area. The estimated 10-percent-in-50-year acceleration decreases to 0.01 g in the western part of the area. For comparison, ground acceleration in Anchorage during the great 1964 earthquake was estimated at 0.16 g. In isolated areas throughout the sale area underlain by thick, soft sediments, the ground accelerations are likely to be higher than in bedrock, due to amplification. However, thick permafrost beneath most of the area may cause the earthquake response of sediments to be more like bedrock, which would limit amplification effects and would also tend to prevent earthquake-induced ground failure, such as liquefaction.

It is standard industry practice that facility siting, design, and construction be preceded by site-specific, high-resolution, shallow seismic surveys which reveal the location of potentially hazardous geologic faults. These surveys are required by the state prior to locating a drilling rig. Facility planners are encouraged to consult with the American Petroleum Institute’s publication, “Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions, Second Edition, December 1, 1995.” This document contains considerations that are unique for planning, designing, and constructing Arctic systems.

The Sale 87 area lies within seismic zones 0 and 1 of the Uniform Building Code (on a scale of 0 to 4, where 4 represents the highest earthquake hazard), and earthquake potential is low. Regardless, all structures in the Sale 87 area should be built to meet or exceed the Uniform Building Code requirements for zone 1 (Combellick, 1994).

[8] An “anticline” is a fold, the core of which contains the stratigraphically older rocks; it is convex upward. The opposite is called a syncline (American Geological Institute, Glossary of Geology, 1973).
[9] Generally, a hinge line refers to a line or boundary between a stable region and a region undergoing upward or downward movement (American Geological Institute, Glossary of Geology, 1973).
[10] A “slump block” is the mass of material torn away as a coherent unit during a block slump. The rotation refers to the apparent fault-block displacement in which the blocks have rotated relative to one another, so that alignment of formerly parallel features is disturbed (American Geological Institute, Glossary of Geology, 1973).
[11] Gravitational acceleration. One g equals an acceleration rate of 32 feet per second per second.

Figure 6.1 Recorded earthquake epicenters in the Sale 87 area.

2. Ice Push

Ice push is the process whereby ice blocks are forced onshore by strong wind or currents and push the sediment from the coast into the ridges farther inland. Throughout the Beaufort Sea, ice push and ice override events can transport and erode significant amounts of sediment. It is most important on the outer barrier islands where ice push ridges up to 2.5 meters high, extending 100 meters inland from the beach have been identified (Hopkins and Hartz, 1978). Over most of the Arctic coast, ice push rubble is found at least 20 meters inland with boulders in excess of 1.5 meters in diameter (Kovacs, 1984). A number of accounts of ice push events have been documented where man-made structures have been damaged along the Beaufort coast. In January of 1984, ice over-topped the Kadluck, an eight-meter-high caisson-retained drilling island located in Mackenzie Bay (Kovacs, 1984).

Ice push has the potential to alter shorelines and nearshore bathymetry, which in the longer term may pose a threat to nearshore facilities with increased erosion. Design parameters to mitigate the effects of ice push are similar to those employed to resist sea ice and coastal erosion forces. These include concrete armoring, berm construction, and coastal facility set-backs.

3. On-Shore Permafrost and Frozen Ground

Permafrost exists throughout most of the onshore Beaufort and is for the most part, a relict[12] feature overlain by a thin layer of seasonally frozen sediment. The thickness has been measured from numerous onshore wells indicating that it thins from east to west. East of Oliktok Point, it has been measured to be 500 meters thick, whereas west of the Colville River it has been measured to be 300 to 400 meters thick (Osterkamp and Payne, 1981). The depth of seasonal thaw is generally less than one meter below the surface and two meters beneath the active stream channels. The ice content varies throughout the region from segregated ice to massive ice in the form of wedges and pingos, and is the highest in the fine-grained, organic-rich deposits and the lowest in the coarse granular deposits and bedrock (Collett and others, 1989).

Ground settlement, due to thawing, occurs whenever a heated structure is placed on the ground underlain by shallow, ice-rich permafrost, and the proper engineering measures are not taken to adequately support the structure and prevent the building heat from melting the ground ice. In addition, the seasonal freeze-thaw processes will cause frost jacking of nonheated structures placed on any frost-susceptible soils unless the structures are firmly anchored into the frozen ground with pilings or supported by non-frost-susceptible fill (Combellick, 1994). The frost susceptibility of the ground is highest in fine-grained alluvium, colluvium, thaw-lake deposits, and coastal-plain silts and sands; moderate in alluvial-fan deposits and till; and lowest in coarse-grained flood-plain deposits, alluvial terrace deposits and gravely bedrock (Carter and others, 1986; Ferrians, 1971; Yeend, 1973a, b).

Frozen-ground problems can be mitigated through proper siting, design, and construction, as has been demonstrated at Prudhoe Bay. Structures, such as drill rigs and permanent processing facilities, should be insulated to prevent heat loss into the substrate. Pipelines can be trenched, back-filled, and chilled (if buried) or elevated to prevent undesirable thawing of permafrost.

4. Waves and Coastal Erosion

Wave heights along the Beaufort coastline are low throughout most of the year because of the short fetch resulting from the pervasive ice cover. However, in the fall open-water season, a considerable fetch can develop both seaward and shoreward of the barrier islands. During this time, storm waves can reach up to 7 to 9 meters when the fetch is equal to 800 km and can become effective erosive agents both onshore and along the exposed faces of the barrier islands (Appel, 1996). Also, wind-induced storm surges can force the ice and water onshore and can raise sea level as much as 3 meters, with an additional meter added to this due to low atmospheric pressures associated with the storms (Barnes and Reimnitz, 1974).

[12] A "relict" feature pertains to a mineral, structure, or feature of a rock that represents those of an earlier rock and which persist in spite of processes tending to destroy it (American Geological Institute, Glossary of Geology, 1973).

Even with the short open-water season along the Beaufort coastline, the wave action, in combination with the melting of coastal permafrost, can cause dramatic rates of coastal erosion. Average rates of erosion across the Beaufort coastline range from 1.5 to 4.7 meters per year with short term erosion rates of 30 meters per year. In one case, near Oliktok Point, the coastline eroded 11 meters during one two-week period (Hopkins and Hartz, 1978a).

The highest rates of erosion occur along the coastal promontories where the bluffs are composed of fine-grained sediments and ice lenses. In some areas, beaches have been formed from the gravel eroded from bluffs composed of coarse-grained deposits and act to partially isolate those bluffs from wave action. In other areas, where the bluffs are composed of fine sediment, the sand eroded from the bluffs do not form protective beaches, causing the bluffs to erode more rapidly. In the Harrison Bay area, where the bluffs are composed primarily of coarser grained sediments, the average retreat rates are between 1.5 to 2.5 meters per year (Craig and others, 1985).

The only prograding (advancing) shoreline areas along the Beaufort coastline occur off the deltas of major rivers. In those areas, the rate of progradation is very slow, such as the Colville River, which averages 0.4 meters per year (Reimnitz and others, 1985).

Bank erosion along the rivers in the region is produced through similar processes, where the sediment cohesiveness is a major factor in determining the river bank erodibility. In this case, the higher erosion rates occur along the braided channels, which usually develop in areas composed of noncohesive sediment (Scott, 1978). In a study along the Sagavanirktok River, aerial photographs showed a maximum erosion rate of 4.5 meters per year during a 20-year period. In this area, most of the erosion appeared to occur in small increments during breakup flooding and was concentrated in specific areas where conditions were favorable for thermo-erosional niching (Combellick, 1994).

Erosion rates, sediment grain size and cohesiveness, river bank stability, and nearshore bathymetry must all be considered in determining facility siting, design, construction, and operation. They must also be considered in determining the optimum oil and gas transportation mode. Structural failure can be avoided by proper facility set-backs from coasts and river banks. Mitigation measure 21 prohibits the siting of permanent facilities, other than road and pipeline crossings, within one-half mile of the banks of the main channel of the Colville, Kuparuk, Sagavanirktok, Shaviovik, Kadleroshilik, Kavik, Echooka, Ivishak, Toolik, Anaktuvuk, Chandler and Canning Rivers. Docks and road or pipeline crossings can be fortified with concrete armor, and the placing of retainer blocks and concrete-filled bags in areas subject to high erosion rates, such as at the Endicott causeway breaches. Mitigation measure 10b prohibits the siting of causeways or docks within river mouths or deltas.

5. Seasonal Flooding

Floods occur annually along most of the rivers and many of the adjacent low terraces due to the seasonal snow melt and ice jamming (Rawlinson, 1993). As the weather warms up, during the spring runoff, the river flood waters inundate the landfast sea ice. At this time of year, large areas of the fast ice are covered with water to depths of up to 1.5 meters, as far as 30 km from the river mouths. When the flood water reaches openings in the ice, it rushes through with enough force to scour the bottom to depths of several meters by the process called strudel scouring (Reimnitz and others, 1974).

In addition to the seasonal flooding, many of the rivers along the coast are subject to seasonal icing prior to the spring thaw. This is due to the overflow of the stream or ground water under pressure, and in the areas of repeated overflow, the residual ice sheets often become thick enough to extend beyond the flood-plain margin. These large overflows and residual ice sheets have been documented on the Sagavanirktok, Shaviovik, Kavik, and Canning Rivers (Dean, 1984; Combellick, 1994).

Storm surges along the Beaufort coast frequently occur in the summer and fall. Sea-level increases of 1 to 3 meters have been observed, with the largest increases occurring on the westward-facing shores. Storm surges can also occur from December through February, although the sea-level elevation changes are generally less than in summer and fall. Decreases in the elevation of the sea-level can occur and occur more frequently during the winter months (MMS, 1995).

Seasonal flooding of lowlands and river channels is extensive along major rivers that drain into the Sale 87 area. Thus, measures must be taken prior to facility construction and field development to prevent losses and environmental damage. Pre-development planning should include hydrologic and hydraulic surveys of spring break-up activity as well as flood-frequency analyses. Data should be collected on water levels, ice floe direction and thickness, discharge volume and velocity, and suspended and bedload sediment measurements for analysis. Also, historical flooding observations should be incorporated into a geophysical hazard risk assessment. All inactive channels of a river must be analyzed for their potential for reflooding. Containment dikes and berms may be necessary to reduce the risk of flood waters that may undermine facility integrity. Mitigation measure 23, discussed in Waves and Coastal Erosion addresses seasonal flooding concerns.

6. Overpressured Sediments

Along the central Beaufort region, extremely high pore pressures can be expected to be found where Cenozoic strata (sedimentary layers) are very thick, such as in the Kaktovik, Camden, and Nuwuk Basins. Onshore, in the Camden Basin, high pore pressures have been measured in both the Tertiary and Cretaceous formations where the burial depths of the Tertiary strata exceeded 3,000 meters (Craig and others, 1985).

In the Point Thomson area, the pore pressure gradients were measured as high as 0.8 pounds per square inch per foot (psi/ft) in sediments at burial depths of 4,000 meters. In this area a pore pressure gradient of 0.433 psi/ft is considered normal (Hawkings and others, 1976). High pore pressures have also been measured throughout the Cenozoic strata of the Mackenzie Delta in the Canadian Beaufort. Here, the pore-pressure gradients were measured as high as 0.76 psi/ft and have been observed at depths as shallow as 1,900 meters (Hawkings and others, 1976).

Drilling mud in the well-bore is mixed to a specific density that will equal or slightly exceed the pressure in the formation. When formation pressures exceed the weight of the drill mud in the well-bore, the result can be a kick[13] or blow-out. Thus, encountering over-pressured sediments while drilling can result in a blow-out or uncontrolled flow. The risk of a blow-out is reduced by identifying locations of overpressured sediments via seismic data analysis, and then adjusting the mud mixture accordingly as the well is drilled. If a kick occurs, secondary well control methods are employed. The well is shut-in using the blow-out prevention (BOP) equipment installed on the wellhead after surface casing is set. The BOP equipment closes off and contains fluid pressures in the annulus and the drillpipe. BOP equipment is required for all wells and surface and sub-surface safety valves are required to automatically shut-off flow to the surface.

7. Shallow Gas Deposits and Natural Gas Hydrates

Shallow pockets of natural gas have been encountered in boreholes throughout the Arctic, both onshore and offshore. This gas usually exists in association with faults that cut Brookian strata, and as isolated concentrations in the Pleistocene coastal plain sediments (Granz and others, 1982b). The presence of shallow gas has been inferred from studies by Boucher and others (1980), Craig and Thrasher (1982), Sellmann and others (1981), and Grantz and others (1982b). Sediments in which gas has accumulated are a potential hazard if penetrated during drilling as well as for any manmade structures on top of them.

Natural gas hydrates commonly occur offshore under low-temperature, high-pressure conditions (Macleod, 1982) as well as at shallower depths associated with permafrost (Kvenvolden and McMenamin, 1980). In the central Beaufort, gas hydrates have been found at shallow depths under permafrost along the inner shelf (Sellmann and others, 1981) as well as onshore at Prudhoe Bay (Kvenvolden and McMenamin, 1980). During drilling, the rapid decomposition of gas hydrates can cause a rapid increase in the pressure in the wellbore, gasification of the drilling mud, and the possible loss of well control. If the release of the hydrate gas is too rapid, a blowout can occur, and the escaping gas could be ignited. In addition, the flow of hot hydrocarbons past a hydrate layer could result in hydrate decomposition around the wellbore and the loss of strength of the affected sediments. If this happened and the well were shut-in for a period, the reformation of the hydrates could induce high pressures on the casing string (MMS, 1995).

[13] A kick is a condition where the formation fluid pressure (pressure exerted by fluids in a formation) exceeds the hydrostatic pressure (pressure exerted by mud in the borehole) resulting in a “kick”; formation fluids enter the borehole.

Because gas hydrates and shallow gas deposits pose risks similar to overpressured sediments, the same mechanisms for blow-out prevention and well control are employed to reduce the danger of loss of life or damage to the environment. For more detail on oil spills and their effects, see Chapter Five. For a discussion of oil spill prevention and response, see Section C of this chapter.

B. Likely Methods of Transportation

If commercial quantities of oil are found in the Sale 87 area, it will go to market via the Trans-Alaska Pipeline System (TAPS), a 798-mile pipeline from Prudhoe Bay to Valdez. From Valdez, the oil is transported to markets in Cook Inlet, the U. S. West Coast, and the U. S. Gulf Coast via tanker. In-field gathering lines bring the oil from individual well sites to processing facilities for injection into TAPS.

Buried or elevated pipelines are the only feasible means for transporting oil and gas from developed fields to TAPS. The advantages and disadvantages of two options are set forth below. It is possible that a transportation system used for oil or gas from the Sale 87 area will be based upon both options. The mode of transport from a discovery will be an important factor in determining whether or not future discoveries can be economically produced. Buried pipelines are more expensive to install and maintain than elevated pipelines. The more expensive a given transportation option is, the larger a discovery will have to be to be economically viable.

1. Elevated Pipelines

Elevated pipelines are typically used in North Slope oil field development to prevent heat transfer from the hot oil in the pipeline to frozen soils, since heat would degrade the permafrost. Elevated pipelines are easy to maintain and visually inspect for leaks. However, above-ground pipelines can restrict caribou and other wildlife movements unless provisions are made to allow for their safe passage. For the Alpine development project, ARCO may gradually increase the standard five foot minimum to accommodate undulating terrain, thus minimizing vertical bends in the pipeline. To further enhance caribou and human crossing, selected portions of the elevated pipeline may be elevated 7 to 8 feet near streams and lakes where caribou and human use are high (Parametrix Inc., 1996:2-8).

There appears to be a cumulative effect of roads and adjacent pipelines that creates a barrier to caribou crossing. Pipelines elevated at least five feet have been shown to be effective except when they were in proximity to roads with moderate to heavy traffic (15 or more vehicles/hour). Roads with low levels of traffic and no adjacent parallel pipeline are not significant barriers to movement of caribou. The Alaska Caribou Steering Committee concludes the most effective mitigation is achieved when pipelines and roads are separated by at least 500 feet. Lessees are encouraged (Lease Advisory 10) in planning and design activities to consider the recommendations for oil field design and operations contained in the final report of the Alaska Caribou Steering Committee (Cronin et al., 1994:10).

2. Buried Pipelines

Buried pipelines are feasible in the Arctic provided that the integrity of the frozen soils is maintained. Such pipeline configurations have been used in the Milne Point area. There are some important considerations regarding long sections of buried pipe. First is cost, which depends on length, topography, soils, and distance from the gravel mine site to the pipeline. Second, buried pipe is more difficult to monitor and maintain. However, significant technological advances in leak detection systems have been made which increase the ease with which buried pipelines can be monitored. These systems are described under the oil spill prevention subsection in Chapter Six. Third, buried pipelines may involve increased loss of wetlands because of gravel fill. Finally, buried pipelines are sometimes not feasible from an engineering standpoint because of the thermal stability of fill and underlying substrate (Cronin et al., 1994:10).

For its Alpine development project, ARCO is planning a buried oil pipeline under the Colville River. The pipeline will be installed at a depth of approximately 50 feet or greater beneath the river bed using horizontal directional drilling methods (Parametrix Inc., 1996:2-12). The pipeline will be insulated and operated such that the oil temperature will ensure that thaw settlement will be within tolerable limits. The leak detection system will employ real-time monitoring supplemented by the use of inspection pigs (ARCO, 1996:6-9). The Colville River pipeline will be designed for a minimum service life of 20 years (ARCO, 1996:6).

3. Mitigation Measures

Any crude oil ultimately produced from Sale 87 tracts will have to be transported to market. It is important to note that the decision to lease oil and gas resources in the state does not authorize the transportation of any oil. If and when oil is found in commercial quantities and production of oil is proposed, final decisions on transporting that oil will be made through the local, state, and federal permitting process. That process will consider any required changes in oil spill contingency planning and other environmental safeguards.

No oil or gas will be transported from the Sale 87 leases until the lessee has obtained the necessary permits and authorizations from federal, state, and local governments. The state has broad authority to withhold, restrict, and condition its approval of transportation facilities. In addition, both the North Slope Borough and the federal government have jurisdiction over various aspects of any transportation alternative. Mitigation measures and lease advisories (listed in Chapter Seven) that mitigate any potential impacts of the selected transportation mode are:

- Measure 7a requires that pipelines be located so as to facilitate the containment and cleanup of spilled hydrocarbons.
- Mitigation Measure 7b requires that pipelines be designed and built to provide adequate protection from geophysical and other hazards.
- Mitigation Measure 8 requires that pipelines be designed and constructed to avoid significant alteration of caribou and other large ungulate movement and migration patterns.
- Mitigation Measure 10 pertains to the maintenance of nearshore oceanographic circulation patterns and fish passage. The state of Alaska discourages the use of continuous-fill causeways. Environmentally preferred alternatives for field development include use of buried pipelines, onshore directional drilling, or elevated structures. Causeways, docks, and other structures may be permitted if the Director, in consultation with ADF&G and ADEC, determines that a causeway or other structures are necessary for field development and that no feasible and prudent alternatives exist. Approved causeways must be designed, sited, and constructed to prevent significant changes to nearshore oceanographic circulation patterns and water quality characteristics (e.g., salinity, temperature, suspended sediments), and must maintain free passage of marine and anadromous fish. Monitoring programs and mitigation, such as breaching, may be required to achieve intended protection objectives.

C. Oil Spill Risk, Prevention and Response

1. Oil Spill History and Risk

Any time crude oil or petroleum products are handled, there is a risk that a spill might occur. Oil spills associated with the exploration, development, production, storage and transportation of crude oil may occur from well blowouts or pipeline or tanker accidents. Petroleum activities may also generate chronic low volume spills involving fuels and other petroleum products associated with normal operation of drilling rigs, vessels and other facilities for gathering, processing, loading, and storing of crude oil. Spills may also be associated with the transportation of refined products to provide fuel for generators, marine vessels and other vehicles used in exploration and development activities. A worst case oil discharge from an exploration facility, production facility, pipeline or storage facility is restricted by the maximum tank or vessel storage capacity or by a well's ability to produce oil. Companies do not store large volumes of crude at their facilities on the North Slope. Produced oil is processed and piped out as quickly as possible. This reduces the possible size of a potential spill on the North Slope.

A well can only spill as much oil as it can produce without assistance. For example, a well with a production rate of 2,500 bbl per day can only spill a maximum of 2,500 bbl per day (Powers 1980:2). A review of the February 1997 production statistics indicates that the average production rate is 1,511 bpd for producing North Slope fields. Some wells cannot produce without mechanical assistance, and if an accident occurs, oil ceases to flow.

a. Exploration and Production

Spills related to petroleum exploration and production must be distinguished from those related to transportation because the phases have different risk factors and spill histories. Exploration and production facilities in the Sale 87 area may include onshore gravel pads; drill rigs; pipelines; and facilities for gathering, processing, storage and moving oil. These facilities are discussed below. When spills occur at these facilities, they are usually related to everyday operations such as fuel transfers. Cataclysmic spills are rare at the exploration and production stages because spill sizes are limited by production rates and by the amount of crude stored at the exploration or production facility.

The most dramatic form of spill can occur during a well blowout which can take place when high pressure gas is encountered in the well and sufficient precautions, such as increasing the weight of the drilling mud, are not effective. The result is that oil, gas, or mud is suddenly and violently expelled from the well bore, followed by uncontrolled flow from the well. Blowout preventers, which immediately close off the open well to prevent or minimize any discharges, are required for all drilling and work-over rigs and are routinely inspected by the AOGCC.

A blowout that results in an oil spill is extremely rare and has never occurred in Alaska. However natural gas blowouts have occurred. An example of a gas blowout occurred in 1992 at the Cirque No. 1 well. The accident occurred while ARCO workers were drilling an exploratory well and hit a shallow zone of natural gas. Drilling mud spewed from the well and natural gas escaped. It took two weeks to plug the well (Anchorage Times, 1992). In 1994, a gas kick occurred at the Endicott field 1-53 well. BP Exploration was forced to evacuate personnel and shut down most wells on the main production island. No oil was released to the surface, as the well had not yet reached an oil-bearing zone. There were no injuries, and the well was killed three days later by pumping heavily weighted drilling muds into it (Schmitz, 1994; Anchorage Daily News, 1994a).

b. Pipelines

The pipeline system that carries North Slope crude from the development area includes gathering lines and pipelines which carry the crude to treatment facilities and to Pump Station 1 where the oil enters TAPS for transport to the port of Valdez. Pipelines vary in size, length and amount of oil contained. A 14-inch pipeline can store about 1,000 bbl per mile of pipeline length. Under static conditions, if oil were lost from a five mile stretch of this pipeline (a hypothetical distance between emergency block valves), a maximum of 5,000 bbl of oil could be discharged if the entire volume of oil in the segment drained from the pipeline.

In January 1994, a pipeline break occurred at a Prudhoe Bay drill site. Investigation showed the failure of the line was caused by wind-induced vibration and the automatic safety valve and alarm had been turned off. Response to the oil spill was swift in containment and cleanup. Most of the oil flowed into an impoundment area and approximately 360 bbl were recovered of an estimated 300-400 bbls spilled. Further investigation found four other wells in the Prudhoe Bay eastern operating area with safety valves turned off (Alaska Journal of Commerce, 1994:4, and Schmitz, 1994). A leak in a Kuparuk pipeline carrying oil to a processing facility was also discovered in 1994. The cause of the two-foot crack in the line has not yet been determined (Schmitz, 1994). The oil flow was shut off and the line depressurized. The breached pipeline carries around 20,000 bbl per day from two drilling sites. About 6,000 square feet of surrounding tundra was affected, but there was no danger to the nearby Ugnuravik River (Anchorage Daily News, 1994:D).

On April 20, 1996 Alyeska Pipeline Company discovered crude oil in an access vault (similar to a manhole) near check valve 92 which is located about 90 miles north of Glennallen. Alyeska and the Joint Pipeline Office (JPO) activated the Incident Command System and dispatched staff to the site and to the emergency operations control center at Alyeska's Anchorage offices. Throughput in the TAPS was reduced from 1.5 million to 850,000 barrels per day during the response. The leak came from a faulty plug on a six-inch bypass line. Check valve 92 is buried about 16 feet below the surface. Alyeska drilled two holes downhill from the valve and removed dirt from around the line in an effort to locate the source of the leak and to determine the extent of impact. The company completed repairs April 25 and recovered about 500 gallons of crude oil from two metal culverts and contaminated soils. (ADEC, 1996)

c. Marine Terminals

There are no marine terminals on the North Slope due to the presence of ice for most of the year. The Valdez terminal receives North Slope crude through TAPS, stores it and loads it onto tanker vessels for transport to the west coast of the United States, Cook Inlet and Pacific Rim. Most North Slope crude is transported to the U.S. west coast. Some North Slope crude is shipped to the Nikiski refinery in Cook Inlet and passes through the Nikiski terminal facility.

The Valdez terminal has maintained records of all spills since startup in 1977. From June 1977 to November 1994, there have been 48 spills greater than 55 gallons from terminal equipment or systems. Of these spills 34 (70 percent) were to land, 10 incidences (20 percent) were to water, and 4 (8 percent) were to both land and water. The causes have been personnel error and equipment failure or unknown. Twenty-six (42 percent) of the spills were North Slope crude, 19 (38 percent) were diesel fuel or lubricants, and 8 (11 percent) were chemicals and water. (Alyeska Pipeline Service Co. 1996)

Petroleum hydrocarbons may enter Port Valdez harbor from ballast water that is off-loaded from incoming tankers. The water is treated to remove residual petroleum hydrocarbons and then discharged via a submarine diffuser into the inlet (Jarvella 1987:582). A four year, pre- and post-operational study undertaken by the University of Alaska (Jarvella 1987, citing Colonell 1980) concluded that no adverse effects on the fjord were presently evident (Jarvella 1987:582). Monitoring continues under National Pollutant Discharge Elimination System (NPDES) permits.

The stationary nature of exploration, production and terminal facilities and the predictability of maximum spill rates based on production rates and storage amounts somewhat simplifies the development and implementation of oil spill contingency plans for those facilities. In contrast, the mobile nature of tankers, the large volumes carried and the exposure to marine hazards places tankers at higher risk for oil spills. A badly damaged tanker can spill millions of gallons of oil in a matter of hours.

d. Tanker Vessels

North Slope crude oil is carried from the Port of Valdez to the U.S. west coast and to the Nikiski refinery in Cook Inlet. Worldwide statistics (excluding the Russian Federation) confirm that tankers, rather than exploration and production activities, present the largest potential for oil pollution. Since the 1980’s, a fairly constant rate of 1.3 spills per billion barrels of oil transported has been shown (Anderson, et al., 1992). Current spill rates for single hull tankers are considerably higher than for pipelines. A tanker accident can result in the release of large quantities of oil in a short time, causing severe environmental damage. An oil spill in a marine water setting is also much more difficult to contain than one on land since ocean currents and tidal actions carry the oil over a much larger area.

Tankers heading south out of Hinchinbrook Entrance stay 50 to 200 miles offshore, depending on each company’s route and sea and ice conditions. The U. S. Coast Guard does not establish the route. Since November 1994, new USCG safety regulations for tankers operating in the Prince William Sound area, especially through the Valdez Narrows, require tankers to add a third tugboat to accompany tankers when winds exceed 20 knots instead of 30 knots. Shippers voluntarily reduced tanker speed through the Narrows from 6 knots to 5 knots to enable a tugboat attached to the back of a tanker to guide the tanker more effectively.

An independent risk assessment study of oil tankers traversing Prince William Sound concludes that current safeguards instituted after the Exxon Valdez oil spill have significantly reduced the risks of oil spills. The study recommended a number of additional improvements to further reduce risk, and the TAPS shippers are instituting many new safeguards. The shippers are working with Alyeska to:

- Charter a high-powered tug for deployment at Cape Hinchinbrook to reduce the risk of a tanker grounding;
- Upgrade the current fleet of tugs with at least two newly enhanced tugs, incorporating risk assessment recommendations and the state’s new "best available technology" regulations;
- Revise tug operating procedures for Valdez Narrows to minimize dangers of human error identified in the risk assessment;

- Work with the U.S. Guard and ADEC to implement a new escort system using prepositioned tugs in central Prince William Sound to reduce the risk of a collision;
- Test new tractor tugs for use in Valdez Narrows; and
- Place new tractor tugs in service as soon as possible if their performance is equal to or better than the tethered-tug system currently in use.

The State, U.S. Coast Guard, and the oil industry have started a safety program to reduce the risks of collisions between fishing vessels and oil tankers. (Oil Spill Intelligence Report, 1996)

During the summer of 1987, the tanker *Glacier Bay* spilled between 2,350-3,800 bbl of North Slope crude oil being transported into Cook Inlet for processing at the Nikiski Refinery (ADEC, 1988:1). Less than ten percent of the oil was recovered, and the spill interrupted commercial fishing activities in the vicinity of Kalgin Island during the peak of the red salmon run. Although not on the scale of the *Exxon Valdez* spill, this spill focused attention on oil spill response and cleanup capabilities in Cook Inlet.

An example of the potential magnitude of a tanker spill is the March 1989 *Exxon Valdez* spill, the largest recorded spill in U.S. waters (nearly 261,900 bbl). Oil from the *Exxon Valdez* contaminated fishing gear, fish, and shellfish, killed numerous marine birds and mammals, and led to the closure or disruption of many Prince William Sound, Cook Inlet, Kodiak, and Chignik fisheries (Alaska Office of the Governor 1989 "*Exxon Valdez* Oil Spill Information Packet"). Effects of the oil spill on fish and other wildlife can be found in this finding in the section entitled Cumulative Effects.

The spills from the *Glacier Bay* and the *Exxon Valdez* were not effectively contained, and the effectiveness of the cleanup efforts remains the subject of controversy. In the case of the *Glacier Bay* spill in Cook Inlet, tidal currents and confusion concerning who would respond to the spill caused response problems. During the *Exxon Valdez* spill in Prince William Sound, the sheer size of the spill quickly overtaxed available cleanup resources at a time when response plans had not been updated or practiced and equipment stockpiles were not sufficient nor easily accessible.

In May 1994, a cracked hull in the *Eastern Lion* allowed approximately 8,400 gallons of crude oil to leak into the port of Valdez while the vessel was berthed at the marine terminal. As a result of analyzing response methods, Alyeska Pipeline purchased shallow draft boats to allow access of tow boom to the shallow duck flats area and a new ramp is to be built at the fish hatchery to move booms more efficiently from shore to water (Alaska Journal of Commerce, 1994a).

The *Glacier Bay* and *Exxon Valdez* incidents demonstrated that preventing catastrophic tanker spills is easier than cleaning them up and focused public, agency, and legislative attention on the prevention and cleanup of oil spills. Numerous changes were made on both the federal and state levels. At the state level, new statutes created the oil and hazardous substance spill response fund (AS 46.08.010), established the Spill Preparedness and Response (SPAR) Division of ADEC (AS 46.08.100), and increased financial responsibility requirements for tankers or barges carrying crude oil up to a maximum of $100 million (AS 46.04.040(c)(1)). The discussion of regulations and laws regarding oil spills is presented later in this section.

2. Oil Spill Prevention

A number of measures contribute to the prevention of oil spills during the exploration, development, production, and transportation of crude oil. Some of these prevention measures are presented as mitigation measures in Chapter Four, and some are discussed at the beginning of this section. Prevention measures are also described in the oil discharge prevention and contingency plans that the industry must prepare prior to beginning operations. Thorough training, well-maintained equipment and routine surveillance are important components of oil spill prevention.

a. Exploration and Production:

The oil industry employs many techniques and operating procedures to help reduce the possibility of spilling oil. The techniques that may be used during exploration include:

- Use of existing facilities and roads.
- Waterbody protection, including proper location of onshore oil storage and fuel transfer areas.

- Use of proper fuel transfer procedures.
- Use of secondary containment, such as impermeable liners and dikes.
- Proper management of oils, waste oils, and other hazardous materials to prevent ingestion by bears and other wildlife.

Should development occur, additional measures include:

- Consolidation of facilities.
- Placement of facilities away from fishbearing streams and critical habitats.
- Siting pipelines to facilitate spilled oil containment and cleanup.
- Installation of pipeline leak detection and shutoff devices.

Each well has a blowout prevention program that is developed before the well is drilled. Operators review bottom-hole pressure data from existing wells in the area and seismic data to learn what pressures might be expected in the well to be drilled. Engineers use this information to design a drilling mud program with sufficient hydrostatic head to overbalance the formation pressures from surface to the total depth of the well. They also design the casing strings to prevent various formation conditions from affecting well control performance. Blowout prevention (BOP) equipment is installed on the wellhead after the surface casing is set and before actual drilling begins. BOP stacks are routinely tested in accordance with government requirements. (BP, 1996)

Wells are drilled according to the detailed plan. Drilling mud and well pressures are continuously monitored, and the mud is adjusted to meet the actual wellbore pressures. The weight of the mud is the primary well control system. If a kick (sudden increase in well pressure) occurs, the well is shut-in using the BOP equipment. The BOP closes off and contains fluids and pressures in the annulus and in the drillpipe. Technicians take pressure readings and adjust the weight of the drilling mud to compensate for the increased pressure. BOP drills are performed routinely with all crews to ensure wells are shut-in quickly and properly. Rig foremen, tool pushers, drillers, derrick men and mud men all have certified training in well control that is renewed annually. (BP, 1996)

If well control is lost and there is an uncontrolled flow of fluids at the surface, a well control plan is devised. The plan may include instituting additional surface control measures, igniting the blowout, or drilling a relief well. Regaining control at the surface is faster than drilling a relief well and has a high success rate. A blowout may bridge naturally due to the pressure drop across the formations. Under these conditions, reservoir formations flow to equalize pressure and the resulting bridging results in decreased flow at the surface. The exact mechanical surface control methods used depend on the individual situation. Operators may pump mud or cement down the well to kill it; replace failed equipment, remove part of the BOP stack and install a master valve; or divert the flow and install remotely-operated well control equipment. (BP, 1996)

At the same time operators are considering mechanical surface control methods, they begin planning to drill a relief well. They assess the situation and determine the location for the relief well and plan the logistics necessary to move another drill rig to the site. Conditions may require the construction of an ice or gravel pad and road. The operator will look for the closest appropriate drill rig. If the rig is in use, industry practice dictates that, when requested, the operator will release the rig for emergency use. Arranging for and drilling a relief well could take from 10 to 15 weeks depending on weather, cause of the blowout, choice of surface location and depth of the well. (BP, 1996)

Leak detection systems and effective emergency shut-down equipment and procedures are essential in preventing discharges of oil from any pipeline which might be constructed in the sale area. Once a leak is detected, valves at both ends of the pipeline, as well as intermediate block valves, can be manually or remotely closed to limit the amount of discharge. The number and spacing of the block valves along the pipeline will depend on the size of the pipeline and the expected throughput rate (Nessim and Jordan, 1986:68). Industry on the North Slope currently uses the volume balancing method. This method involves comparing input volume to output volume.

The technology for monitoring pipelines is continually improving. Leak detection methods being researched outside Alaska include acoustic monitoring, pressure point analysis, and combinations of some or all of the different methods (Yoon, Mensik, and Luk 1988). The approximate location of a leak can be determined from the sensors along the pipeline. A computer network is used to monitor the sensors and signal any abnormal responses. In recent years, computer based leak detection through a Real-Time Transient Model to minimize spills has come into use. This technology can minimize spills from both new and old pipelines (Yoon and Mensik, 1988).

A similar technology for detecting leaks in oil and gas pipelines is termed Pressure Point Analysis (PPA). The method uses measured changes in the pressure and velocity of the fluid flowing in a pipeline to detect and locate leaks. PPA has successfully detected holes as small as 1/8-inch in diameter within a few seconds to a few minutes following a rupture (Farmer, 1989:23). Automated leak detection systems such as PPA operate 24 hours per day and can be installed at remote sites. Information from the sensors can be transmitted by radio, microwave, or over a hard wire system.

Design and use of “smart pigs,” data collection devices that are run through the pipeline while it is in operation, has greatly enhanced the ability of a pipeline operator to detect internal and external corrosion and differential pipe settlement in pipelines. These pigs can be sent through the pipeline on a regular schedule to detect changes over time and give advance warning of any potential problems. The TAPS operation has pioneered this effort for Arctic pipelines. The technique is now available for use worldwide and represents a major tool for use in preventing pipeline failures.

If pipelines are used in the development of the Sale 87 area, operators would follow the appropriate American Petroleum Institute recommended practices. They would inspect the pipelines regularly to determine if any damage was occurring and would also receive regular maintenance. Preventive maintenance includes installing improved cathodic protection, using corrosion inhibitors and continuing regular visual inspections.

b. Marine Terminals

The fixed location of loading facilities at marine terminals improves oil spill response and contingency planning. If a leak occurs, the facility can be rapidly shut down and the spill contained. Spill prevention measures include extensive inspection programs, monitoring of transfer operations, use of proper valves, overfill alarms, construction of secondary and tertiary containment systems around the tanks, facility security programs, training, and drug and alcohol testing of personnel. More detailed information regarding these programs are included in the oil discharge prevention and contingency plans for Alyeska’s Valdez terminal and Kenai Pipe Line Company’s Nikiski terminal.

c. Tanker Vessels:

Tankers are the most cost effective and the only feasible method for transporting crude oil from Alaska to destinations in the Pacific Rim. Federal legislation through OPA 90 requires the phase-out of single-hulled tankers in favor of double-hulled tankers by the year 2010. Double-bottomed tankers, where at least 30 percent of the area beneath the cargo tank length has two bottoms, are an approved interim measure.

Several of the tankers transiting Prince William Sound are double-hulled, and OPA 90 requires tankers in Prince William Sound to be accompanied by two escort vessels to Hinchinbrook Entrance. Escort tugs are to keep tanker vessels off the rocks should the tanker lose power. Alyeska Pipeline Company’s response organization, SERVS, maintains five escort response vessels and four tug escort vessels for this purpose. As a result of a recent risk assessment, a high-power escort tug will be stationed at Hinchinbrook. (Lisiechki, 1997) See the discussion on Oil Spill History and Risk for additional details regarding risk-reduction actions in Prince William Sound.

Tesoro contracts for two double-bottomed tankers, the *Chesapeake Trader* and the *Potomac Trader* to bring North Slope crude from Valdez to the Nikiski complex in Cook Inlet for refining. The vessels are hydrostatically loaded, in which tankers are only partially filled with crude so that if a tank were breached, the difference in pressure would cause sea water to flow in rather than the oil to flow out. Other features that may reduce the risk of oil spills during transport include on-deck cargo piping, inert gas system for all cargo tanks, approved vapor recovery systems for use during cargo transfer, and emergency towing packages at the bow and stern.

Many carriers voluntarily follow various other practices that also reduce the risk of oil spills. These practices may include having two licensed officers or one licensed officer and one licensed marine pilot on deck at all times, keeping anchors ready for emergency use when traversing high risk areas, plotting fixes frequently, conducting unscheduled anchoring drills in the lower inlet, performing regular maintenance procedures and special inspections in preparation for the winter climate, and incorporating special adaptations for tanker use in severe winter conditions**.**

All tanker crews participate in spill prevention and response training and substance abuse testing. The oil discharge prevention and contingency plans for Alyeska's and Tesoro's vessel operations contain more detailed information regarding spill prevention programs.

3. Oil Spill Response

a. Incident Command System (ICS)

The ICS system is designed to organize and manage responses to incidents involving a number of interested parties in a variety of activities. Since oil spills usually involve multiple jurisdictions, the joint federal/state response contingency plan incorporates a unified command structure in the oil and hazardous substance discharge ICS. The unified command usually consists of the Federal On-Scene Coordinator, the State On-Scene Coordinator, the Local On-Scene Coordinator and the Responsible Party On-Scene Coordinator. Industry and agency personnel in the operations, logistics, planning and finance sections of the incident command system gather information and make recommendations on objectives and strategies to the unified command. A Multi-Agency Coordination group made up of government agencies with local jurisdiction and other concerned parties may also provide input to the unified command. (ADEC, 1994)

The Unified Command jointly makes decisions on objectives and response strategies. However, only one Incident Commander is in charge of the spill response. The Incident Commander is responsible for implementing these objectives and response strategies (AS 46.04.200(b)(2) and (3)). The Responsible Party Incident Commander may remain in charge until or unless the Federal On-Scene Coordinator and the State On-Scene Coordinator decide that the Responsible Party is not doing an adequate job of response. (ADEC, 1994)

b. Response Teams

The Alaska Regional Response Team (ARRT) monitors the actions of the Responsible Party. The Team is composed of representatives from 15 federal agencies and one representative agency from the state. The ARRT is co-chaired by the U.S. Coast Guard and Environmental Protection Agency. ADEC represents the state of Alaska. The team provides coordinated federal and state response policies to guide the Federal On-Scene Coordinator in responding effectively to spill incidents. The ARRT has developed guidelines regarding wildlife, in situ burning, and the use of dispersants. A working group is developing guidelines for the protection of cultural resources, which include archaeological and historic sites. (ADEC, 1994)

Each North Slope operator identifies a spill response team (SRT) for their facility, and each facility must have an approved spill contingency plan. Company teams provide on-site, immediate response to a spill event. The responders first attempt to stop the flow of oil and may deploy boom to confine oil that has entered the water. The responders may deploy boom to protect major inlets, wash-over channels, and small inlets. Finally, deflection booming would be placed to enclose smaller bays and channels to protect sensitive environmental areas. If the nature of the event exceeds the facility's resources, the Responsible Party calls in its response organization. The Spill Response Team (SRT):

1) identifies the threatened area;
2) assesses the natural resources, i.e., environmentally sensitive areas such as major fishing areas, spawning or breeding grounds;
3) identifies other high-risk areas such as offshore exploration and development sites and tank-vessel operations in the area;
4) obtains information on local tides, currents, prevailing winds, and ice conditions; and
5) identifies the type, amount, and location of available equipment, supplies and personnel.

The next action would be containment. It is especially important to prevent oil spills from reaching the Beaufort Sea where they could spread rapidly over a large area. Cleanup activities continue as long as necessary, without any time frame or deadline. A winter spill might require initial on-site response followed by further cleanup of oil melting out of the ice in the spring or summer (USDOI, MMS 90-0063:M-5).

c. Training

Individual members of the SRT train in basic spill response; skimmer use; detection and tracking of oil; oil recovery on lakes; river booming; radio communications; ATV, snowmobile, and four-wheeler operations; oil discharge, prevention, and contingency plan review; communication equipment operations; Arctic survival; oil spill burning operations; pipeline leak plugging; and spill volume estimations.

d. Response Organizations

Alaska Clean Seas (ACS) is the spill response organization for the North Slope operators. Its area of responsibility covers the North Slope between the Colville and Canning rivers and includes the Alyeska Pipeline corridor to Pump Station No. 4 and the three-mile offshore limit of state waters.

In 1995, ACS was given increased management of all spill response equipment, with the charge to standardize preventative maintenance procedures, develop a common equipment data base, and to strategically reposition spill equipment based on risk. Other duties include record keeping, training, drills and deployment in response situations.

ACS has assigned a lead technician position and a supporting spill technician position to each of the three large fields on the North Slope (Kuparuk, Eastern Operations Area, and Western Operations Area). They have been given responsibility for initial containment and recovery operations under management by the Responsible Party (RP) in those fields and in the vicinity of those fields. In addition to response, these ACS positions conduct and coordinate preventative maintenance and repair of equipment, along with equipment inventorying, pre-staging and pre-deployment (ACS, 1995:2).

Immediate spill response requirements will continue to be met through the use of Spill Response Teams (SRTs) comprised of company and contractor employees at each of the fields who voluntarily enlist in their particular field's SRT. The SRTs are integrated into a single North Slope Spill Response Team (NSRT), comprised of 115 field responders per shift, each of which has or will receive 40 hours of hazardous materials (HAZWOPER) training. The North Slope Operators who furnish the SRTs from their employee and contractor staffs have committed to make the SRT's available on a Slope-wide basis for up to 36 hours upon call-out (ACS, 1995:3).

ACS and the North Slope operators employ a "tiered system" for responding to spills. Small, non-emergency spills are cleaned up by the Operator or ACS personnel. Spills requiring the resources of ACS and the responsible party's SRT are considered "Level I" spills. Depending on activity levels and the duration of work to do, off-site contractor-supplied personnel may be used to complete the cleanup and may be obtained through one or more of the master agreements which ACS maintains with labor contractors (ACS, 1995:3).

If a spill requires more than the resources of ACS and the RP, it is considered to be a Level II spill. Additional manpower resources would be obtained through mutual aid. Mutual aid is a system that utilizes SRTs from companies other than that of the responsible party. Such spills usually require some longer term cleanup. Under its master service agreements, ACS can obtain 100 contract responders within 36 hours (ACS, 1995:3).

If a spill exceeds the resources available on the North Slope, it is classified as a Level III spill. These types of spills will not only receive initial response from the full North Slope Response Team (NSRT), but will likewise require the work of off-site contract responders under ACS's master service agreements (ACS, 1995:3).

ACS established a central Incident Command Post at Deadhorse as a control point for oil spill response radio and telephone systems for the entire North Slope area which extends north from 68 degrees latitude (approximately Cape Seppings on the Chukchi Sea) and east to the Canadian border, including a range of several hundred miles offshore in the Chukchi Sea. This radio and telephone communications system is capable of being rapidly deployed by sea, land, or air to local and remote areas in support of offshore exploration or oil spill response actions. Remote control circuits for nine permanent Very High Frequency

(VHF) repeaters and marine coast stations, installed at strategic locations in the production area and pipeline corridor, are routed via private microwave circuits into the system. Other High Frequency (HF) and Ultra High Frequency (UHF) radios are also connected to the system. Communication is then possible among all users, whether marine-based radios, company headquarters or supply depots, ICP, hand held portable radios, or aircraft radios. This gives each member company access to all of the radio systems, regardless of the type of radio it is using. ACS also has mobile VHF radios and about 150 hand held radios for field use in its oil spill response program (ACS 1991, Vol. 1, No. 2:3), (ACS 1991 Deadhorse Spill Response Telecommunication Center).

Other operational equipment includes four INMARSAT satellite telephone systems, operating independently of wires and separate from the VHF, UHF, and other radio systems, at Deadhorse on the North Slope. The name INMARSAT is derived from “international, marine, satellite.” The system can reach anywhere in the world via satellite. An INMARSAT system can be mounted on a boat, in such a way that, regardless of heavy seas or other disturbance, the antenna beam cannot be shaken off the satellite and communication disconnected. Ships, barges, aircraft, oil spill response agencies, ground personnel, and anyone with a telephone can be reached via this system. The equipment is operational now and can be used immediately in case of an emergency anywhere in the state (Wheeler, personal communication, 1991).

ACS designed and built an oil skimmer called Shallow Water Access Mop Platform (SWAMP) for use in the shallow waters between the shore and barrier islands. The vessel is a catamaran with pontoons for hulls. It uses a rope mop of sorbent material that moves through the floating oil and soaks it up. A wringer then removes the oil. The pilot house can be removed and the entire boat can be loaded on a C-130 aircraft for transport to the spill location (LPRC 1989, Vol. 1, No. 1:1).

Acquisitions by ACS include two 38-foot response boats and a 45-foot response boat known as the “Big Dipper,” which is an aluminum hulled boat that operates efficiently in only 25 inches of water. The boat is equipped with two LORI skimmers and two 6,000 lb. capacity hydraulic autocranes and has a pulling capacity of 6,500 lbs. (ACS 1991, Vol. 1, No. 1:8).

ACS is also involved with state and federal agencies and local community groups in training North Slope village teams to support oil spill response capability. Intensive training courses for the village team members include winter and summer oil spill operations, hazardous waste operations, oil spill post-emergency response, oil spill assessment, tracking and detection of oil, skimmer operations, incident command, and basic radio voice procedures. The teams take part in field exercises and the annual North Slope mutual aid response exercises. Village members have been asked to provide training for other team members in survival techniques in the arctic, small boat operation techniques in arctic waters, and environmental concerns, because of their unique knowledge of the arctic environment (ACS 1991, Vol. 1, No. 1:2-8).

ACS developed a wildlife protection strategy in cooperation with federal and state government agencies. The strategy utilized guidelines taken from the Wildlife Guidelines for Alaska in the Alaska Region Oil and Hazardous Substances Pollution Contingency Plan produced by the Regional Response Team. Three areas of concern were identified: 1) controlling spilled oil at the source to prevent or reduce contamination of species or their habitat; 2) keeping wildlife away from oiled areas through deterrent techniques; 3) capture and treatment of oiled wildlife. Training courses are being developed to ensure that the hazing, capture, and stabilization are conducted safely for both the wildlife and the personnel involved (ACS 1991, Vol. 1, No. 3:1).

The Alaska Regional Response Team (ARRT) signed a Memorandum of Agreement in February 1991 pre-approving in situ burning as a spill response technique for ACS areas of responsibility north of the Brooks Range and in the Beaufort and Chukchi Seas. Pre-approval vests the final decision with the Federal On-Scene Coordinator (U. S. Coast Guard offshore; EPA or BLM onshore) and facilitates quick decision making (ACS 1991, Vol. 1, No. 1:5).

Important aspects of response are planning, preparation and practice. Each year North Slope and Beaufort Sea operators and state and federal agencies participate in a mutual aid drill.

4. Cleanup and Remediation

Cleanup plans for terrestrial and wetlands spills must balance the objectives of maximizing recovery while minimizing ecological damage. Many past cleanup operations have caused as much or more damage than the oil itself. All oils are not the same, and knowledge of the chemistry, fate and toxicity of the spilled oil can help identify those cleanup techniques that can reduce the ecological impacts of an oil spill. Hundreds of laboratory and field experiments have investigated the fate, uptake, toxicity, behavioral responses, and population and community responses to crude oil. (Jorgenson, 1996)

The best techniques are those that quickly remove volatile aromatic hydrocarbons. This is the portion of oil that causes the most concern regarding the physical fouling of birds and mammals. To limit the most serious effects, it is desirable to remove the maximum amount of oil as soon as possible after a spill. The objective is to promote ecological recovery and not allow the ecological effects of cleanup to exceed those caused by the spill itself. Table 6.1 lists cleanup objectives and techniques that may be applicable to each objective. Table 6.2 compares the advantages and disadvantages of cleanup techniques for crude oil in terrestrial and wetland ecosystems. (Jorgenson, 1996)

Table 6.1 Objectives and Techniques for Cleaning Up Crude Oil in Terrestrial and Wetland Ecosystems (Adapted from Jorgenson, 1996)

Objectives	Cleanup Techniques
Minimize:	
Movement of oil	Absorbent booms Sand bagging Sheet piling
Surface-water contamination	Same as above
Soil infiltration	Flood surface
Soil and vegetation contact and oil adhesion	Flood surface Use surfactants to reduce adhesion
Vegetation damage	Use boardwalks to reduce trampling Use flushing instead of mechanical techniques Perform work when vegetation is dormant
Thawing of Permafrost	Avoid vegetation and surface disturbance
Wildlife contact with oil	Fencing to prevent wildlife from entering site Plastic sheeting to prevent birds from landing on site Guards to haze wildlife Devices to haze wildlife
Acute and chronic toxicity of oil to humans, fish, and wildlife	Removal of oil Enhance biodegradation of remaining oil
Waste disposal	Use flushing Avoid absorbents and swabbing
Cost	Remove oil as fast as possible Achieve acceptable cleanup level quickly to minimize monitoring
Liability	Achieve acceptable cleanup level
Maximize:	
Recovery potential of tundra ecosystems	All of the above Add nutrients to aid recovery of plants
Worker safety	Air testing, training, clothing

Table 6.2 Advantages and Disadvantages of Techniques for Cleaning Up Crude Oil in Terrestrial and Wetland Ecosystems (Adapted from Jorgenson, 1996)

Technique	Advantage	Disadvantage	Recommended
Wildlife:			
Fencing	Keeps out large mammals	Does not keep out birds	Yes
Plastic sheeting	Keeps out both birds and mammals	Can no longer work area	Sometimes
Wildlife guard	Flexibility to respond	Higher cost	Sometimes
Devices	Lower cost	Animals become habituated	No
Containment:			
Absorbent booms	Contains floating oil, quickly deployed	Misses water soluble oil	Yes
Sand bags	Contains both floating and soluble fractions, follows tundra contours	Slower to mobilize, some leakage	Yes
Sheet piling	Maximum containment	Slow to install, doesn't fit contours well	Sometimes
Earthen berms	Can easily be adapted to terrain, heavy equipment rapidly can create berms	Destroys existing vegetation and soil	No
Snow/ice berms	Can be used during winter cleanup or to prevent runoff during breakup	Can only be used during freezing periods	Yes
Contact:			
Flooding	Keeps heavy oil suspended	Spreads out oil	Yes
Surfactants	Reduces stickiness, aids removal, and reduces volatilization	Reduces effectiveness of rope mop skimmer	Yes
Thickening agents	Untried, aids physical removal	Must be well drained, physical removal more difficult	No
Access:			
Boardwalks	Reduces trampling	None	Yes
Removal:			
Complete excavation	Eliminates long-term liability	Eliminates natural recovery, disposal costs	Sometimes
Partial excavation	Quickly reduces oil levels, less waste to dispose of than complete excavation	Causes partial ecological damage, disposal costs, still long-term liability	Sometimes
Burning	Low cost, high removal rate	Little testing, ecological damage	Sometimes
Flushing, high pressure	High removal rate	High ecological damage	No
Flushing, low pressure, cold	Moderate removal rate, little damage, easy waste disposal	Spreads oil, not as effective as warm water	No
Flushing, low pressure, warm	High removal rate, little vegetation damage, easy disposal of waste	Spreads oil	Yes
Aeration	Accelerates volatilization	Volatiles lost to air, may pose risk to humans	Yes
Raking	Can target hot spots	Partial vegetation damage	Sometimes
Cutting and trimming	Targets hot spots, reduces stickiness	Partial vegetation damage	Sometimes

Technique	Advantage	Disadvantage	Recommended
Swabbing	Targets hot spots	Not very effective, adds to waste disposal, adds to trampling	No
Oil skimmers and rope mops	Removes heavier oil, works well with flooding, lowers disposal costs	Requires personnel to push oil to skimmer, adds to trampling	Yes
Vacuum pumping	Removes surface and miscible oil, works well with flooding, lowers disposal cost	None	Yes
Biodegradation	Removes low levels of hydrocarbons, non- destructive, lowers disposal costs	Long-term monitoring, site maintenance, may require wildlife protection	Yes

After a spill, the physical and chemical properties of the individual constituents in the oil begin to be altered by the physical, chemical, and biological characteristics of the environment. This is called weathering. As much as 40 percent of most crude oils may evaporate within a week after a spill. The factors that are most important during the initial stages of cleanup are the evaporation, solubility and movement of the spilled oil. Over the long term, microscopic organisms (bacteria and fungi) break down oil. (Jorgenson, 1996)

Cleanup phases include initial response, remediation and restoration. During initial response, the spiller gains control of the source of the spilling oil; contains the spilled oil; protects the natural and cultural resource; removes, stores and disposes of collected oil; and assesses the condition of the impacted areas. During remediation, the responsible party performs site and risk assessments; develops a remediation plan; and removes, stores and disposes of more collected oil. Restoration attempts to re-establish the ecological conditions that preceded the spill. The restoration phase usually includes a monitoring program to access the results of the restoration activities. (Jorgenson, 1996)

5. Regulation of Oil Spill Prevention and Response

a. Federal Statutes and Regulations

Section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) (42 U.S.C. ß9605), and section 311(c)(2) of the Clean Water Act as amended (33 U.S.C. ß 1321(c)(2)) require environmental protection from oil spills. CERCLA regulations contain the National Oil and Hazardous Substances Pollution Contingency Plan (40 C.F.R. ß 300). Under these regulations, the spiller must plan to prevent and immediately respond to oil and hazardous substance spills and be financially liable for any spill cleanup. If the pre-designated Federal On-Scene Coordinator (FOSC) determines that neither timely nor adequate response actions are being implemented, the federal government will respond then seek to recover cleanup costs from the responsible party.

The Oil Pollution Act of 1990 (OPA 90) requires the development of facility and tank vessel response plans and an area-level planning and coordination structure to coordinate federal, regional, and local government planning efforts with the industry. OPA 90 amended the Clean Water Act (Section 311(j)(4)) which established area committees and area contingency plans as the primary components of the national response planning structure. In addition to human health and safety, these area committees have three primary responsibilities:

1. prepare an area contingency plan;
2. work with state and local officials on contingency planning and preplanning of joint response efforts, including procedures for mechanical recovery, dispersal, shoreline cleanup, protection of sensitive areas, and protection, rescue and rehabilitation of fisheries and wildlife; and
3. work with state and local officials to expedite decisions for the use of dispersants and other mitigating substances and devices.

In Alaska, the area committee structure has incorporated state and local agency representatives, and the jointly prepared plans coordinate the response activities of the various governmental entities that have responsibilities regarding oil spill response. The area contingency plan for Alaska is the Unified Plan and is discussed below. Since Alaska is so large and geographically diverse, the federal agencies have found it necessary to prepare sub-area contingency plans, also discussed in the Government Contingency Plans section below.

OPA 90 also created two citizen advisory groups, the Prince William Sound and the Cook Inlet Regional Citizens Advisory Councils. The non-profit organizations provide citizen oversight of terminal and tanker operations that may affect the environment in their respective geographic areas. They also foster a long term partnership between industry, government and citizens and carry out responsibilities identified in section 5002 of OPA 90. These include providing recommendations on policies, permits and site-specific regulations for terminal and tanker operations and maintenance and port operations, monitoring terminal and tanker operations and maintenance, and reviewing contingency plans for terminals and tankers and standards for tankers.

The Prince William Sound Regional Citizens Advisory Council (PWSRCAC) consists of 18 member organizations, including communities impacted by the *Exxon Valdez* oil spill, a Native regional corporation and groups representing fishing, aquaculture, environmental, tourism and recreation interests in the impacted area. PWSRCAC is certified under OPA 90 and operates under a contract with Alyeska. The contract, which is in effect as long as oil flows through TAPS, guarantees the council's independence, provides annual funding, and ensures the PWSRCAC the same access to terminal facilities as state and federal regulatory agencies.

b. Alaska Statutes and Regulations

As discussed in Chapter One, ADEC is the agency responsible for implementing state oil spill response and planning regulations under AS†46.04.030. The Departments of Fish and Game and Natural Resources assist ADEC in these efforts by providing expertise and information. The industry must file oil spill prevention and contingency plans with ADEC before operations commence. ADNR and ADF&G review and comment to ADEC regarding the adequacy of the industry oil discharge prevention and contingency plans (C-plans).

c. Industry Contingency Plans

C-plans for exploration facilities should include a description of methods for responding to and controlling blowouts; the location and identification of oil spill cleanup equipment; the location and availability of suitable drilling equipment; and an operations plan to mobilize and drill a relief well. If development and production should occur, additional contingency plans must be filed for each facility prior to commencement of activity, as part of the permitting process. Any vessels transporting crude oil from the potential development area must also have an approved contingency plan.

AS 46.04.030 provides that no person may:

1. operate an oil terminal facility, a pipeline, or an exploration or production facility, a tank vessel, or an oil barge, or
2. permit the transfer of oil to or from a tank vessel or oil barge, unless an oil discharge prevention and contingency plan has been approved by ADEC, and the operator is in compliance with the plan (AS 46.04.030(a),(b),(c)).

Parties with approved plans are required to have sufficient oil discharge containment, storage, transfer, cleanup equipment, personnel, and resources to meet the response planning standards for the particular type of facility, pipeline, tank vessel, or oil barge (AS 46.04.030(k)). Examples of these requirements are:

- The operator of an oil terminal facility must be able to "contain or control, and clean up" a spill volume equal to that of the largest oil storage tank at the facility within 72 hours. That volume may be increased by ADEC if natural or manmade conditions exist outside the facility which place the area at high risk (AS 46.04.030(k)(1)).

- Operators of exploration or production facilities, or pipelines, must be able to "contain, control, and cleanup the realistic maximum oil discharge within 72 hours." (AS 46.04.030(k)(2)). The "realistic maximum oil discharge" means "the maximum and most damaging oil discharge that [ADEC] estimates could occur during the lifetime of the tank vessel, oil barge, facility, or pipeline based on (1) the size, location, and capacity; (2) ADEC's knowledge and experience with such; and (3) ADEC's analysis of possible mishaps." (AS 46.04.030(q)(3)).

- For crude oil tank vessels and oil barges with a cargo volume of less than 500,000 bbls, the plan holder must be able, at a minimum, to contain or control, and clean up a discharge of 50,000 bbls within 72 hours (AS 46.04.030(k)(3)(A)). For capacities of 500,000 bbls or more, the cleanup volume must be 300,000 bbls within 72 hours (AS 46.04.030(k)(3)(B)). Additionally, all crude oil tank vessel operators must also maintain equipment, personnel, and other resources as necessary to control or contain and clean up a realistic maximum discharge within the shortest possible time (AS 46.030(k)(3)(C)).

Discharges of oil or hazardous substances must be reported to ADEC on a time schedule depending on the volume released, whether the release is to land or to water, and whether the release has been contained by a secondary containment or structure. For example, any discharge of oil to water in excess of 55 gallons on land not within an impermeable secondary containment area or structure must be reported as soon as the operator has knowledge of the discharge (18 AAC 75.300(a)(1)(B) and (C)).

The discharge must be cleaned up to the satisfaction of ADEC, using methods approved by ADEC. If ADEC determines that clean up efforts are inadequate, the department will either order the person engaged in cleanup operations to use additional methods or to cease cleanup activities, or authorize other agents to begin cleanup activities, or both (18 AAC 75.337(a)). The Departments of Fish and Game and Natural Resources advise ADEC regarding the adequacy of cleanup.

A C-plan must describe the existing and proposed means of oil discharge detection, including surveillance schedules, leak detection, observation wells, monitoring systems, and spill-detection instrumentation. AS 46.04.030; 18 AAC 75.425(e)(2)(E). A C-plan and its preparation, application, approval, and demonstration of effectiveness requires a major effort on the part of facility operators and plan holders. The C-plan must include a response action plan, a prevention plan, and supplemental information to support the response plan (18 AAC 75.425). These plans are described below.

The Response Action Plan (18 AAC 75.425(e)(1) Part 1) must include an emergency action checklist of immediate steps to be taken if a discharge occurs. The checklist must include:

1. names and telephone numbers of people within the operator's organization who must be notified, and those responsible for notifying ADEC;
2. information on safety, communications, and deployment, and response strategies;
3. specific actions to stop a discharge at its source, to drill a relief well, to track the location of the oil on open water, and to forecast the location of its expected point of shoreline contact to prevent oil from affecting environmentally sensitive areas;
4. procedures for boom deployment, skimming or absorbing, lightening, and estimating the amount of recovered oil;
5. plans, procedures, and locations for the temporary storage and ultimate disposal of oil contaminated materials and oily wastes;
6. plans for the protection, recovery, disposal, rehabilitation, and release of potentially affected wildlife; and
7. if shorelines are affected, shoreline clean up and restoration methods.

The Prevention Plan (18 AAC 75.425(e)(2) Part 2) must:

1. include a description and schedule of regular pollution inspection and maintenance programs;
2. provide a history and description of known discharges greater than 55 gallons that have occurred at the facility, and specify the measures to be taken to prevent or mitigate similar future discharges;
3. provide an analysis of the size, frequency, cause, and duration of potential oil discharges, and any operational considerations, geophysical hazards, or other site-specific factors, which might increase the risk of a discharge, and measures taken to reduce such risks.

The Supplemental Information Section (18 AAC 75.425(e)(3) Part 3) must:

1. include bathymetric and topographic maps, charts, plans, drawings, diagrams, and photographs, which describe the facility, show the normal routes of oil cargo vessels, show the locations of storage tanks, piping, containment structures, response equipment, emergency towing equipment, and other related information;
2. show the response command system; the realistic maximum response operation limitations such as weather, sea states (roughness of the sea), tides and currents, ice conditions, and visibility restrictions; the logistical support including identification of aircraft, vessels, and other transport equipment and personnel;
3. include a response equipment list including containment, control, cleanup, storage, transfer, lightering, and other related response equipment;
4. provide non-mechanical response information such as in situ burning or dispersant, including an environmental assessment of such use; and
5. provide a plan for protecting environmentally sensitive areas and areas of public concern.

The current statute allows the sharing of oil spill response equipment, materials, and personnel among plan holders. ADEC determines by regulation the maximum amount of material, equipment, and personnel that can be transferred, and the time allowed for the return of those resources to the original plan holder (AS 46.04.030(o)). The statute also requires the plan holders to "successfully demonstrate the ability to carry out the plan when required by [ADEC]" (AS 46.04.030(r)(2)(E)). ADEC regulations require that exercises shall be conducted to test the adequacy and execution of the contingency plan. No more than two exercises are required annually, unless the plan proves inadequate. ADEC may, at its discretion, consider regularly scheduled training exercises as discharge exercises (18 AAC 75.485(a) and (d)).

d. Financial Responsibility

Holders of approved contingency plans must provide proof of financial ability to respond (AS 46.04.040). Financial responsibility may be demonstrated by one or a combination of 1) self-insurance; 2) insurance; 3) surety; 4) guarantee; 5) approved letter of credit; or 6) other ADEC-approved proof of financial responsibility (AS 46.04.040(e)). Operators must provide proof of financial responsibility acceptable to ADEC as follows:

- for crude oil terminals: $50 million in damages per incident.
- for a non-crude oil terminal: $25 per incident for each barrel of total non-crude oil storage capacity at the terminal or $1 million, whichever is greater, with a maximum of $50 million.
- for pipelines and offshore exploration or production facilities: $50 million per incident.
- for onshore production facilities: $20 million per incident.
- for onshore exploration facilities: $1 million per incident.
- for crude oil vessels and barges: $300 per incident, for each barrel of storage capacity or $100 million, whichever is greater.
- for non-crude oil vessels and barges: $100 per barrel per incident or $1 million, whichever is greater, with a ceiling of $35 million AS 46.04.040(a),(b),(c).
- The coverage amounts are adjusted every third year based on the Consumer Price Index. AS 46.04.045.

e. Government Contingency Plans

In accordance with AS 46.04.200, ADEC must prepare, annually review, and revise the statewide master oil and hazardous substance discharge prevention and contingency plan. The plan must identify and specify the responsibilities of state and federal agencies, municipalities, facility operators, and private parties whose property may be affected by an oil or hazardous substance discharge. The plan must incorporate the incident command system, identify actions to be taken to reduce the likelihood of occurrence of "catastrophic" oil discharges and "significant discharges of hazardous substances" (not oil), and designate the locations of storage depots for spill response material, equipment, and personnel. The state master plan has been combined with the federally required area plan to create the "Alaska Federal/State Plan for Response to Oil and Hazardous Substance Discharges/Releases," also known as the Unified Plan. (ADEC, 1994).

ADEC must also prepare and annually review and revise a regional master oil and hazardous substance discharge prevention and contingency plan (AS 46.04.210). The regional master plans must contain the same elements and conditions as the state master plan but are applicable to a specific geographic area. The regional plans are being developed in conjunction with the federally required sub-area plans as "Sub-Area/Regional Contingency Plans" for each of the ten designated contingency planning areas. The sub-area plan for the North Slope is in preparation at this time.

6. Mitigation Measures

Recognition of the difficulties of containment and clean up of oil spills has encouraged innovative and effective methods of preventing possible problems and handling them if they arise. Oil spill prevention, response, and cleanup and remediation techniques are continually being researched by state and federal agencies and the oil industry. Although the risk of impact from a spill cannot be reduced to zero, such risk can be minimized through preventive measures, monitoring, and rigorous response capability. In addition to addressing the prevention, detection, and cleanup of releases of oil, Lessee Advisory 7 requires that lessees' contingency plans address the method to be used to detect, respond to, and control blowouts. Also under this measure, contingency plans must identify the location of oil spill cleanup equipment; the location and availability of suitable alternative drilling equipment; and develop a plan of operations to mobilize and drill a relief well.

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